Aggregate Ramp Rates Analysis of Distributed PV Systems in 5 Locations at San Diego County

Juan L Bosch, Mohammad Jamaly and Jan Kleissl

Dept. of Mechanical and Aerospace Eng., University of California, San Diego

February 6, 2013

Abstract

Aggregate ramp rates of 209 distributed photovoltaic (PV) systems clustered on 5 feeders in San Diego County, CA were analyzed (Alpine, Fallbrook, Ramona, San Diego and Valley Center). Satellite derived irradiance data was utilized to estimate the aggregated power production for each area during the year 2011. The goal was to quantify the largest aggregate ramp rates and determine the success of day-ahead forecast products to predict these ramps. Over one year the largest hourly aggregate absolute ramp was a 78% decrease and hourly ramps over 27% occurred about once per day (ramps are expressed as a fraction of Performance Test Conditions rating). Numerical Weather Prediction models were unable to forecast most ramps day-ahead, but there was some success in forecasting the intra-day variability.

1. Introduction

Integration of large amounts of photovoltaic (PV) into the electricity grid poses technical challenges due to the variable solar resource. Solar distributed generation (DG) is often behind the meter and consequently invisible to grid operators. The ability to understand actual variability of solar DG will allow grid operators to better accommodate the variable electricity generation for resource adequacy considerations that inform planning, scheduling, and dispatching of power. From a system operator standpoint, it is especially important to understand when aggregate power output is subject to large ramp rates. If in a future with high PV penetration all PV power systems were to strongly increase or decrease power production simultaneously, it may lead to additional cost or challenges for the system operator to ensure that sufficient flexibility and reserves are available for reliable operations.

In this study, aggregate ramp rates of distributed PV systems installed in San Diego, CA and surrounding area are analyzed. Modeled irradiation data along with specifications of 209 PV systems are used to evaluate the frequency, magnitude, and ability to forecast large ramps in the aggregate power output. The methodology is described in Section 2. Results of the detected largest ramps in aggregate power output are presented in Section 3 and Section 4 contains the conclusions.

2. Methodology

2.1. Datasets

The California Solar Initiative (CSI) rebate program database includes street address and PV system specifications including AC Rating (kW_{AC}) at performance test condition (PTC, typically 14% less than STC), inverter maximum efficiency, panel azimuth and tilt angles, and tracking type. The PTC rating simulates more realistic conditions at 1000 W m^{-2} plane-of-array irradiance with panel temperature derived from ambient air temperature at 20^{o}C and 1 m s^{-1} wind speed. Given the rapid increase in solar distributed generation (DG) in most coastal urban centers in California (like San Diego which is the focus of this study), this dataset is complete enough to project future effects of high PV penetration on the electric grid. From the 2011 CSI database, specifications for 79 PV power plants on the five feeders were obtained. 130 additional sites were identified using aerial imagery in Google Earth. Site specifications were derived from the measured projected surface areas of each site by assuming a DC conversion efficiency of 15% and a DC-rating to PTC-rating ratio of 0.852. Azimuth and tilt angles were randomly selected from the specifications of nearby (same feeder) sites contained in the CSI database. Therefore, a final set of 209 PV systems with total PTC rated capacity of 4.62 MW, mean PTC rated of 22 kW, and median PTC rated of 4.7 kW are analyzed (Fig. 1). Table 1 shows the characteristics of the different feeders. Notably on the Valley Center and Fallbrook feeders, the largest site (1 MW) constitutes more than half of the total capacity, which reduces geographic diversity effects.

Initially we attempt to use measured PV power output provided by Sullivan Solar Power and the California Solar Initiative Performance-Based Incentive (PBI) program to compute aggregate ramps. This was unsuccessful due to the small number of sites with a full year of data. Only the Point Loma and Fallbrook feeders had more than one such site, but at only 2 and 4 sites the diversity effects due to geography and installation angles of the wide variety of PV systems connected to each feeder were not adequately represented. Therefore, PV output power is estimated based on satellite imagery and a PV performance model.

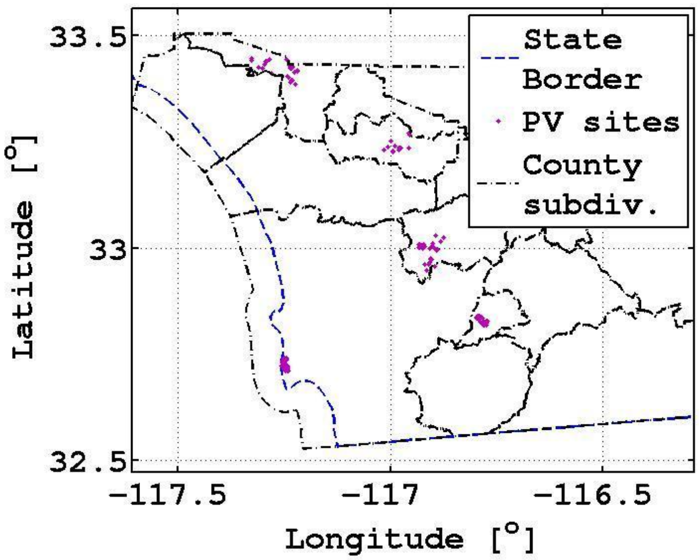


Fig. 1: Map of Sites: Map of 209 PV systems in SDG&E territory. The PV sites are clustered on the feeders in (from North to South) Fallbrook, Valley Center, Ramona, Alpine, Point Loma.

Table 1: Feeders description: Names, total PTC rating and number of sites feeding the 5 areas. The PTC rating of the largest site is shown in brackets.

Feeder name	Site number	Aggr PTC rating [kW]	Mean Distance [km]
Alpine	28	170 [11]	1.4
Fallbrook	28	1160 [1000]	4.5
Ramona	43	239 [13]	2.9
Point Loma	91	1151 [159]	1.3
Valley Center	19	1900 [1005]	2.6

Modeled Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) are provided by Clean Power Research’s commercially available SolarAnywhere (SAW) derived from Geostationary Operational Environmental Satellite (GOES) visible imagery [2]. To obtain GHI, a cloud index is calculated for each pixel from the reflectance measured by the satellite.

Instantaneous, spatially averaged GHI is then calculated by using the cloud index along with a clear sky model that considers regional and seasonal effects of turbidity [3]. SAW enhanced resolution satellite-derived irradiation with 30-min temporal and 1 km spatial resolutions is applied in this study. SAW can be purchased for operational applications with less than 30 min latency.

At each PV system, the SAW derived GHI and DNI are used to estimate power output P by using a performance model as described in [4]. The analysis is conducted for January 1st to December 31st, 2011. To avoid errors due to sensor cosine response and shading by nearby obstructions (not considered by SAW), only data for solar zenith angles less than 75° are considered. Performance when the solar zenith angle is less than 75º for a flat plate system is less than 26% of rated capacity so hourly ramps are likely to be substantially less during those periods.

2.2. Aggregate PV Ramp Rates

The aggregate SAW modeled power output for each area of study is used to determine the largest absolute ramp rates in 2011. From the aggregate PV power output at each time step, differences are calculated for different ramp duration intervals; 30-min through 5-hour in 30-min increments.

We present normalized absolute ramp rates to facilitate scaling the results to future PV penetration scenarios (assuming a similar geographic diversity). Therefore, the aggregate power outputs are normalized by the aggregate (PTC) kW_{AC} capacity of the PV systems for each area (Figs. 2, 3).

2.3. Day ahead forecast

In addition, day-ahead forecasts of the PV power production have been calculated for each of the 209 sites. A high-resolution (1.3 km), direct-cloud-assimilating Numerical Weather Prediction (NWP) model based on the Weather and Research Forecasting model (WRF) forecasts instantaneous hourly GHI day ahead [5]. Satellite observations of cloud cover at model initialization are assimilated into the model. Forecasts with (WRF_A) and without (WRF) cloud assimilation have been calculated for May and June 2011 when the marine layer cloud events are more frequent in the coastal areas. These forecasts have been used to determine the next day expected variability and compared with the measured variability.

2.3.1 Daily Variability Index

Following a method developed at UC San Diego and Sandia National Labs [5, 6], the daily variability is calculated for each day in terms of a Variability Index (VI). The VI was modified to allow the use of aggregated PV power output (rather than irradiance):

$$\mathrm{VI} = \frac{\sum^{\mathrm{day}} |\mathrm{RR}|}{\sum^{\mathrm{day}} |\mathrm{RR_{clear}}|},$$

where the absolute values of the 1-hour ramp rates (*RR*) are summed and divided by the sum of the absolute 1-hour ramp rates that would have occurred if the day was clear (RR_{clear}). This index will be 1 for a clear day and larger than 1 for days with partial cloud cover. It can also take values below 1 for overcast days. Both WRF forecasts (with and without cloud assimilation) and the clear sky model provide global horizontal irradiance (GHI), which is then transformed to PV power output following the same model applied to the SAW database earlier.

3. Results

3.1. The Largest Ramps

3.1.1. Largest Ramp Rates by Time Horizon

The largest step sizes in the absolute aggregate PV power output (normalized by kW_{AC}) are detected over the year for different intervals (Fig. 2). As expected, the maximum ramp magnitude increases with the ramp interval approaching 90% for 5 hour ramps reflective of the diurnal cycle (e.g. from zero output at 0700 to near maximum output at 1200 solar time) on a clear day. However, the ramp magnitudes are already at 65 to 77% over 30 minutes, which is much larger than the SDG&E-wide ramps observed in [Jamaly, Bosch, Kleissl 2012]. The reason is the relatively small geographic diversity within a feeder. A fast-moving cloud front can cover an entire feeder in 30 to 60 minutes causing large ramps, which is especially true for the mountain conditions in Alpine.

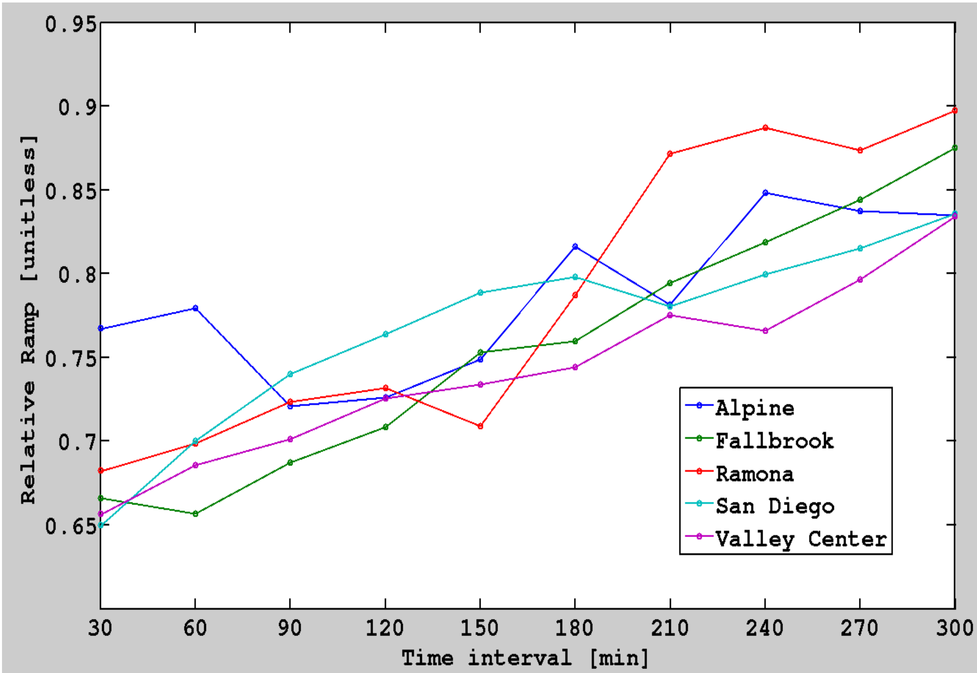


Fig. 2: Largest absolute ramps: Largest ramp magnitude versus ramp time interval (from 30-min upto 5-hours) for aggregate normalized output (P/kW_{AC})

3.1.2. Histogram of large hourly ramps

1-hour ramps have a special significance as most energy exchange between electric balancing areas is currently scheduled over hourly intervals. The distribution of hourly absolute ramp rates in the aggregate PV output (Fig. 3) shows that ramps over 27% h^{-1} of PTC capacity are rare, occurring only for 154 hours of the year. For smaller ramps, the distribution decreases linearly. The differences between the feeders are relatively small; only the coastal San Diego feeder shows slightly more large ramps presumably due to the overall more cloudy conditions.

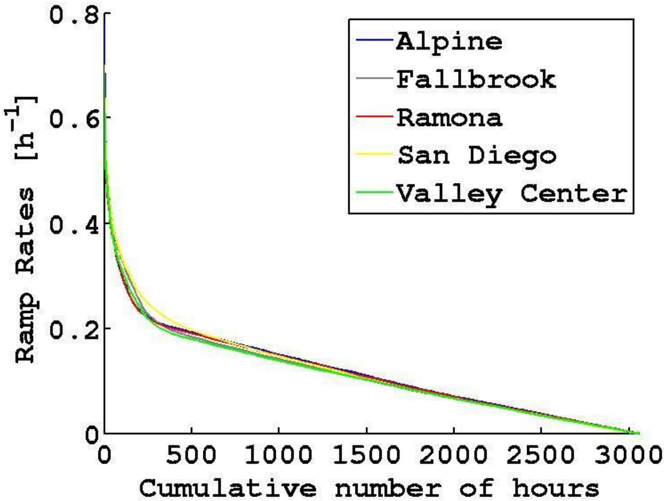


Fig. 3: Distribution of hourly ramp rates: Cumulative distribution of absolute value of 1-hour ramp rates of aggregate absolute 30-min output (normalized by kW_{AC}) from all 209 PV sites grouped by area. The ramps are zero for the remaining hours up to 8760 h, because these are night time conditions.

Fig. 4 shows a histogram (by month) of the 1-hour absolute ramp rates of aggregate normalized power output (normalized by kW_{AC}) which are larger than 27% of PV capacity. The number of ramps is largest from February through May. From June to October most ramps are up-ramps which are caused by marine layer cloud evaporation that coincides with increasing solar altitude.

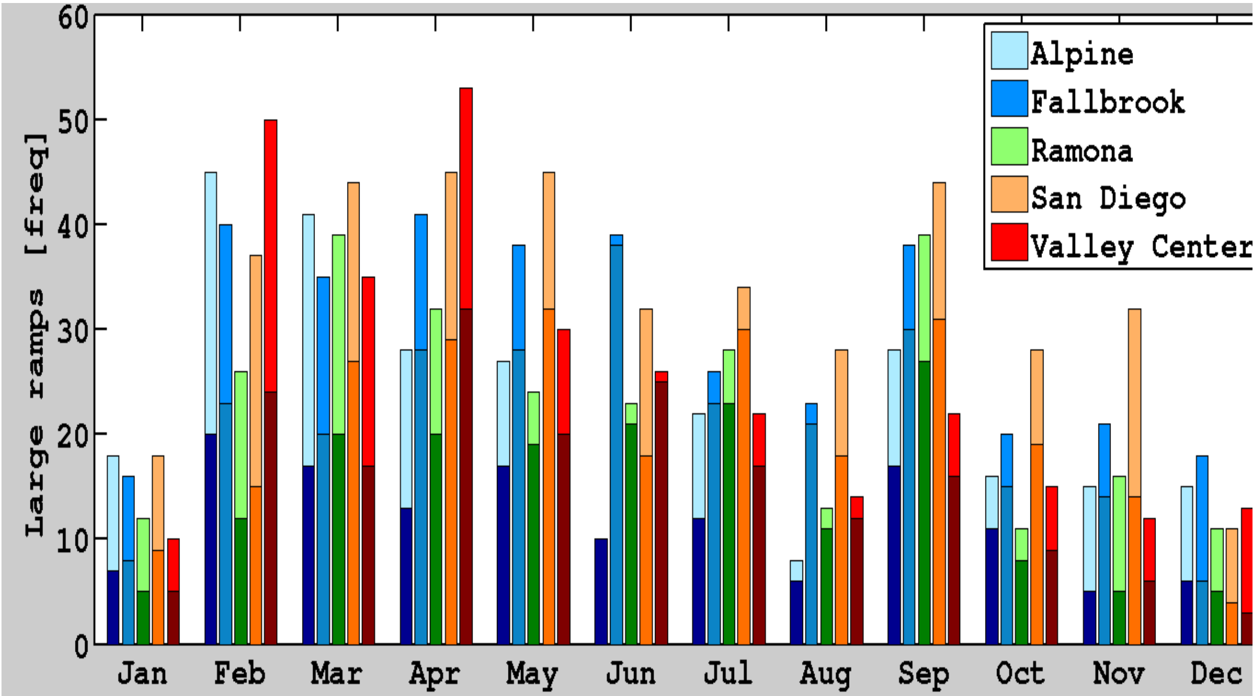
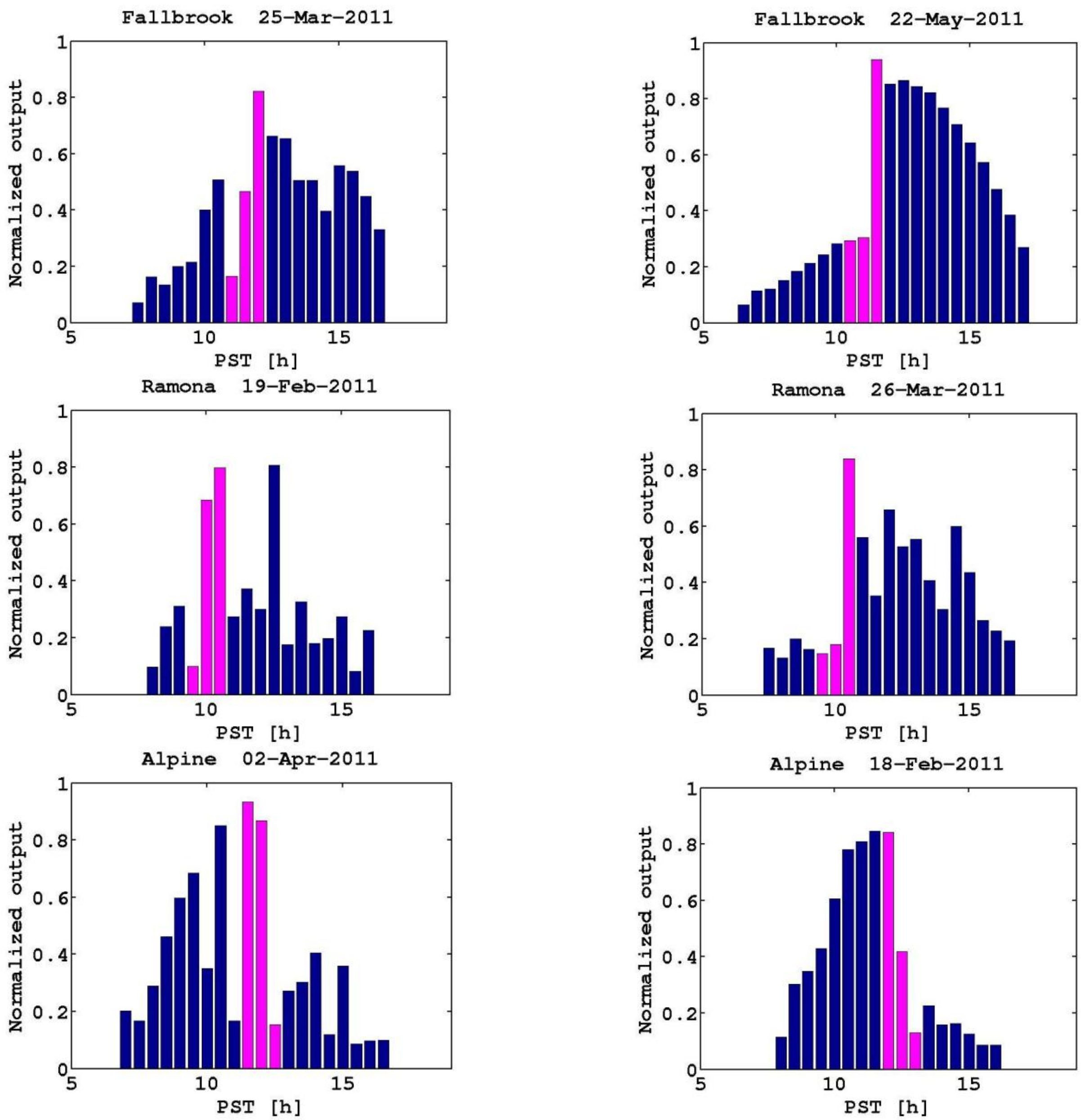


Fig. 4: Month of occurrence and direction (up or down) of large absolute ramps: Histogram of the largest (>27% of PTC capacity) 1-hour ramp rates of aggregate absolute 30-min output (P/kW_{AC}) from all 209 PV sites grouped by feeder location. Dark color bar (at bottom) represent the number of up ramps, while clear color (at top) represents the number of down ramps.

3.1.3 Days with the largest hourly absolute ramps

Fig. 5 shows daily profiles of the normalized aggregate SAW modeled power outputs for the days when the two largest absolute ramps were observed for each feeder. The largest ramp overall caused a change of 78% of PTC capacity within one hour at the Alpine feeder. The largest ramps occur on different days for each feeder, but 9 out of 10 days are between mid-February to early April. All of the largest ramps occur between 0930 and 1400 PST.


Fallbrook 25-Mar-2011
Fallbrook 22-May-2011
Ramona 19-Feb-2011
Ramona 26-Mar-2011
Alpine 02-Apr-2011
Alpine 18-Feb-2011
Normalized output
PST [h]
0
0.2
0.4
0.6
0.8
1
5
10
15

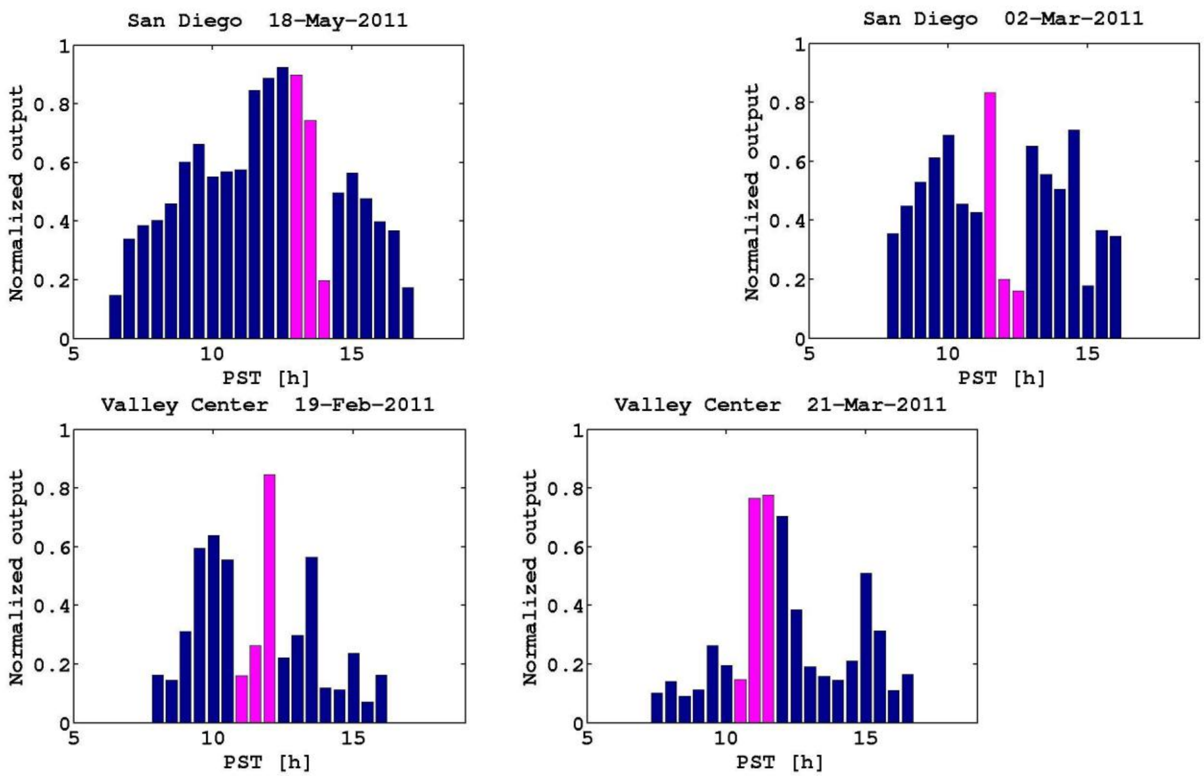


Fig. 5: Ten days with the largest absolute ramps: Normalized aggregate 30-minute PV output from all 5 areas (blue bars) for the days with the largest 1-hour ramp rates in 2011 (magenta bars show the timing of the large ramp).

3.2. Day-Ahead Forecast Performance

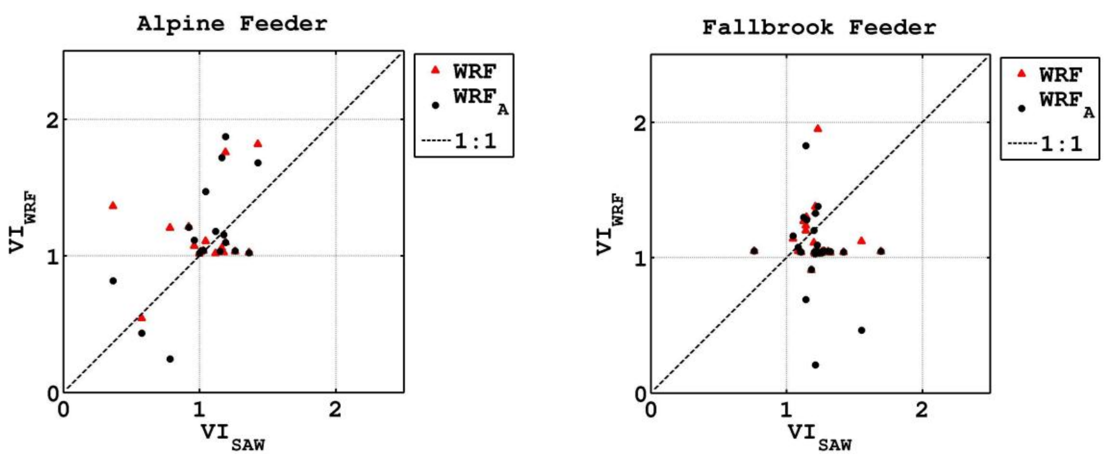
First the day-ahead forecast skill in predicting the days with the five largest 1h ramps for the 5 feeder areas in May - June 2011 were examined using WRF_A. For Alpine, two of the five days with the largest ramps were forecasted correctly; for the Fallbrook region, only the day with the largest ramp was correctly forecasted, and only the second largest was detected for the Ramona feeder. For Point Loma, only the fourth largest ramp and for Valley Center only the third largest ramp were correctly forecasted. In summary only few of the very large ramps can be forecast correctly day-ahead from numerical weather prediction.

Then variability metrics were compared across the May and June period. Clear days that were correctly forecasted were excluded to focus on the more interesting cases of cloudy days when the largest ramps will occur. For Alpine 18 days remain, containing 5 days forecasted as clear that were actually partially cloudy, and 3 days with morning marine layer events (overcast morning and clear afternoon) that will have a VI close to 1. For Fallbrook 28 days remain, with 4 days wrongly forecasted as clear and 14 marine layer days. For Ramona there are 24 remaining days, with 7 cloudy days forecasted as clear, and 8 marine layer days. Point Loma feeder has the lowest number of completely clear days, resulting in 53 remaining days, with 9 days wrongly forecasted as clear and most of the days showing marine layer events. For the Valley Center feeder there are 20 remaining days, with 4 cloudy days forecasted as clear and 5 marine layer days.

Figure 6 shows the Variability Indices calculated from both the *WRF* and the WRF_A forecasts versus the *VI* obtained from *SAW*. A detailed analysis of the discrepancies between forecasted and measured (satellite-based) ramps shows the following error patterns:

- If the WRF forecasts indicate completely overcast days while the measurement show a mix of clear and cloudy periods, then a large underestimation in VI is observed (as in the WRF_A points below 0.5 for the areas of Fallbrook, Ramona and Valley Center).

- VI's are often concentrated close to the WRF = 1 line for all regions. These are due to a wrong clear or marine layer day forecast (with VI~=1) compared to a more variable day measured with VI ranging from 1 to 1.5.



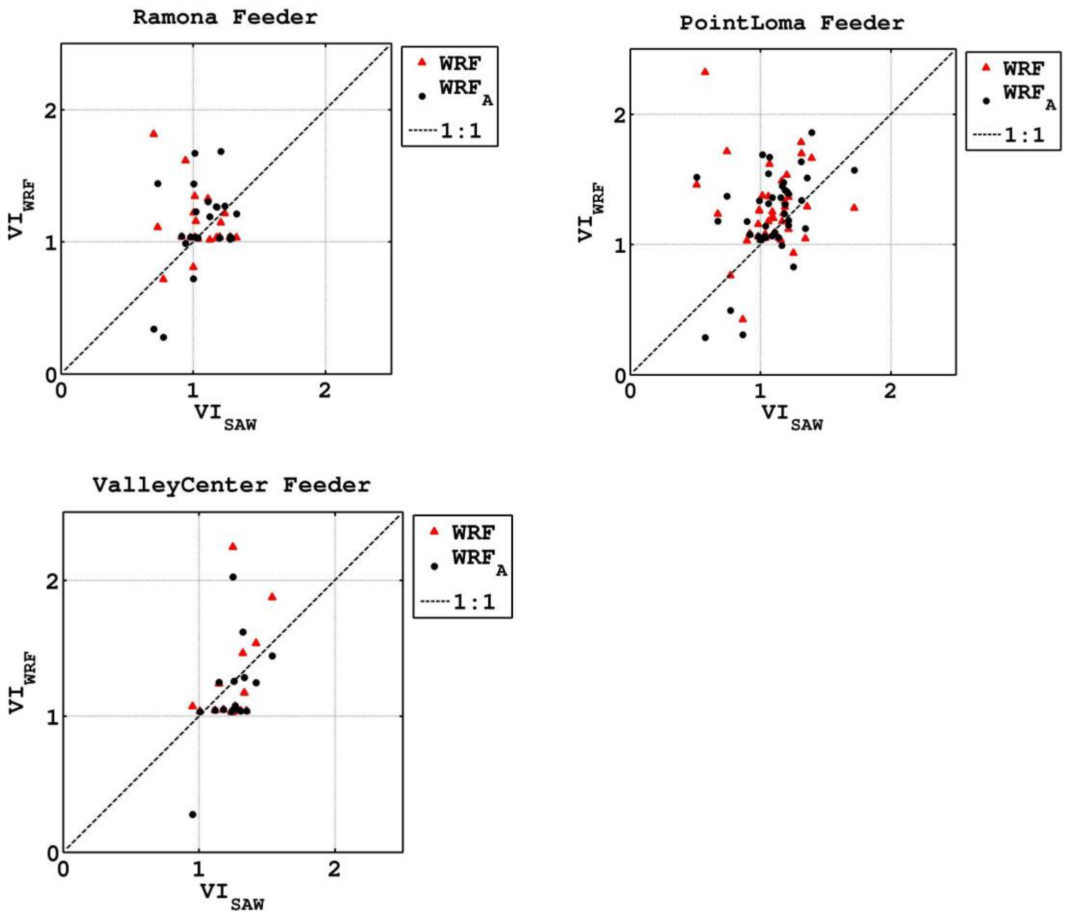


Fig. 6: Variability Index correlation between forecast and measured data for the 5 feeders. The value obtained with both WRF day-ahead forecasting methods is plotted against the Variability index calculated from the SolarAnywhere database.

4. Conclusions

Aggregate ramp rates of 209 PV systems installed on five feeders in SDG&E territory were calculated from satellite derived data. Many of the largest ramps from June through October are caused by summer marine layer breakup when cloud evaporation coincides with an increase in solar altitude nearly every morning. During the winter months, the ramp rates are mainly caused by winter frontal storm systems; when fast-moving storm systems move into the area (creating a large down ramp) or out of the area (creating a large up-ramp).

This analysis was focused on distributed PV generators less geographically diverse than those analyzed in previous reports. As expected this resulted in larger ramps (with a maximum of 78% per 30 minutes) than those observed for PV systems that were relatively well distributed across the SDG&E service area (with a maximum of 44% per 30 minutes).

Day ahead power output forecasts from high-resolution Numerical Weather Prediction model did not show significant skill in forecasting large ramps, even statistically. Further research is required to improve NWP forecasts.

5. References

1 California Solar Initiative, "California Public Utilities Commission California Solar Initiative Program Handbook," Accessed Sep. 2011 at: http://www.gosolarcalifornia.org/documents/CSI_HANDBOOK.PDF

2 Web-based Clean Power Research service database, SolarAnywhere. Available: https://www.solaranywhere.com/Public/About.aspx

3 R. Perez, P. Ineichen, K. Moore, M. Kmiecik, C. Chain, R. George, and F. Vignola, "A new operational model for satellite-derived irradiances: Description and validation," Solar Energy, 73(5):307-317, 2002.

4 M. Jamaly, J.L. Bosch, and J. Kleissl, Power Output Analysis of Distributed PV Systems in California Using SolarAnywhere Enhanced Resolution Irradiation, CSI Report, 2012.

5 P. Mathiesen, C. Collier, and J. Kleissl, "A high-resolution, cloud-assimilating numerical weather prediction model for solar irradiance forecasting." Solar Energy, In Press, 2013.

6 J.S. Stein, C. W. Hansen and M. J. Reno, "The Variability Index: A new and novel metric for quantifying irradiance and PV output variability" ASES conference 2012.